Updating Output Emission Limitation Workgroup
Wednesday, February 3, 1999
12:30 PM to 5:00 PM
Hotel Washington
515 15th St. NW, Washington DC

Introductions and review of agenda

Larry Kertcher served as moderator for the meeting. He began by explaining that the purpose of the Workgroup is to help EPA develop guidance for using output-based emissions for future allocations as the SIP call process moves forward. Most initial allocations will be based on the historical input-based approach, however, EPA would like to understand what issues are associated with switching to an output-based allocation (e.g., monitoring, measuring, and reallocating as update cycles occur).

The premise behind this Workgroup meeting is that EPA will develop guidance for an output-based approach as another option for States to use in their SIPs. Thus, EPA would like to answer "What is the best way and what considerations are associated with an output-based approach (e.g., net versus gross and accounting for steam from cogeneration units) ?" The issue of allocating allowances only to fossil fuel generation or all generation sources may be addressed in future meetings rather than this meeting because it affects whether to move forward with an output-based approach. EPA's tentative plan for future meetings[1] includes the following:

- March Workgroup meeting dedicated to discussions on transitioning to an output-based approach;
- April Workgroup meeting dedicated to "how to;" and
- May Workgroup meeting dedicated to presentations from EPA staff presenting, for members critique, their reactions to the issues and a tentative proposal describing "how to" that may be included in a guidance document, at a later date, for States to use.

Overview of Workgroup responses to EPA issues

Margaret Sheppard gave a brief review of the issues raised during the December 17th and 18th conference calls:

- Increasing State representation (which has been addressed in part and is reflected in the attendance at this meeting).

[1]This does not reflect modifications to the schedule based on a subsequent telephone conversation between EPA and Workgroup participants on February 18, 1999.

- Weighing the benefits of output-based and input-based systems relative to different types of generation.
- Identifying an appropriate timeframe and determining what needs to be done to achieve the system's goals, if an updating system is used.
- Examining allocations (input- and output-based) and ozone transport regions within States.

Conference callers agreed to have this Feb. 3-4 meeting to follow up on these issues. Ms. Sheppard asked if members had changes to the meeting summary. One member asked for clarification of the statement "If an updating system is chosen, the proposal will not impact the first three years of allocations" (page four of the summary). Ms. Sheppard explained that in the SIP call, EPA committed to developing guidance for updating allocations. Updating is not as much an issue for the initial allocation, and EPA cannot develop necessary guidance by September 1999. Joel Bluestein will present his alternative approach for calculating intial output-based allocations at the February 4th Workgroup meeting. A member commented that New York must complete its allocations by early April and does not have the information necessary to use an output-based allocation. Mr. Kertcher added that EPA is committed to providing States with guidance on switching to an output-based approach; however, the Agency believes it needs more information, hence this Workgroup. Sarah Dunham confirmed that with the initial allocation, there is a State option to allocate only the first of the three years of allowances upfront. In subsequent years, States can allocate for a year that is three years in the future. Thus, if output data becomes available in 2001, States could allocate allowances on an output-basis for 2005.

Ms. Sheppard commented that the papers submitted by Workgroup members were very helpful. She summarized her understanding of the information the papers presented and requested members feedback. (The questions and answers were summarized in a slide presentation. See slides for details.)

Workgroup members were responding to a series of questions concerning the following issues:

(1) What are sources of information that States need to determine and update allocations on a periodic basis in terms of electric generation, steam (thermal), and mechanical output?

(2) What equipment do sources use to measure output (e.g., what standardized equipment widely available and used in the field, and what is the accuracy of equipment)?

(3) Is it necessary to convert heat input, steam output, and electrical output? How would this be done if it is necessary? If it is not necessary, how else would a State allocate?

(4) How do States receive output data for setting future allocations?

Electric generation information needed by States

In discussing auxiliary usage, it was noted that it might be difficult to separate electricity used by pollution control equipment from other parasitic loads. A facility may group plant equipment and pollution control equipment together. Process use of power (i.e., power generated and used within the facility for industrial processes that are not auxiliaries) should be added to the categories of generation.

In discussing supporting records needed for electrical output, many members noted that the accuracy of meters should not be that great of a concern because it is usually between 0.1 and 0.3 percent. Another good quality check may be to compare electrical output with sales information.

Members divided into two camps with regard to measuring gross generation at the generator or net generation after power plant requirements have been consumed. One member proposed a variant of net generation involving subtracting auxiliaries that are plant inefficiencies. The details of these calculations would have to be worked out.

In response to the question, "how can EPA or States allocate based on generation measured at the plant level," one member noted that most electrical power plants can measure net MWh output at the unit level. But in cases where there are only plant level measurements, one could allocate net output to the unit level using gross output or other factors. Most members noted that unit level allocations are unnecessary. One could just have a plant level account. The plant operator would have to show that allowances for the entire plant cover emissions from all units or stacks at the plant. EPA may need to modify its tracking system and may internally discuss the options available. One member asked why EPA would need to modify its tracking system? Ms. Sheppard replied that plant level accounts (perhaps similar to the OTC NOx budget program) would have to be developed. The mechanics of getting the accounts into the system, checking numbers against each other, and issues of minority versus majority operators and accountability would have to be addressed.

Dan Lashof stressed that the proposed option should not change the compliance determination. One could still use a compliance determination at the plant level. Ms. Sheppard described reconciliation in the Acid Rain Program when there is a common stack (e.g., three units emit to a common stack). The plant designated representative must allocate emissions from the common stack to each unit. This may be a possibility for tracking and reconciliation or one could use gross MW to divide the allocation. Ms. Sheppard noted that EPA will return to this issue.

Mike Geers asked if Mr. Lashof was looking for compliance based on tons emitted or on an emissions rate/MW. The former would be easy; one could use CEMS data. The latter, however, involves allocating MW back to a specific boiler, which can be judgement sensitive. Mr. Lashof responded that tons emitted would be enough. Mr. Kertcher commented that the compliance determination can be by unit or plant. Depending on what people choose, EPA may need to modify the computer software. A member commented that permitting is generally not done across the board at the facility level. Emissions are measured on an emissions unit level.

There is no problem with continuing to ask for compliance on a unit level basis, even if one is allocating allowances to a plant that may have more than one unit.

Steam output information needed by States

With regard to measuring steam (or thermal) output, Ms. Sheppard will follow up with individuals to identify ASTM specifications that provide testing and measurement, and what frequency this would be done. One person suggested quality assuring steam output measurements by checking sales information.

Equipment sources used to measure output

Ms Sheppard noted that the only question that did not receive a response was "Is the error different for steam and electricity?" She suggested more follow up be done on this question.

Converting heat input, steam output, and electrical output

Ms. Sheppard noted that these questions focused particularly on cogenerators and that Workgroup members disagreed on whether steam output should be converted to electrical output. The new NSPS NOx standard gives a 50 percent credit for steam.

Dwight Alpern asked if EPA's definition of "cogenerator" is that used by the Federal Energy Regulatory Commission, where a sequential use of energy is required, or does the term apply to any facility producing steam and electricity. Ms. Sheppard replied that she was thinking of the latter, although EPA will think about this in more depth when drafting the definition of cogenerating units. She welcomed members' opinions on this topic.

Receiving output data for future allocations

Members suggested that sources not reporting output data could be asked for it, as EPA did in the proposed Federal Implementation Plans; could be restricted from allowance trading; or could be penalized by assuming a low conversion efficiency. Mr. Kertcher suggested the presenters evaluating advantages and disadvantages of "gross" versus "net" provide their assessments of the reliability of output data and its availability.

One member asked what is the range of net across facilities with and without control equipment (i.e., what is the range of net, as a fraction of gross, across auxiliaries and congenerators). Ms. Sheppard said that papers she read reported that typically three to six percent of the gross output is used internally, depending on emission controls. This percentage can be as high as 12 percent, though, if one has the full range of emission controls and inefficient internal use. The member confirmed that this answer helps in deciding that it is good to further investigate the difference between net and gross. If the answer had been a small percentage, like two percent, it would not be an issue.

Members did not raise any additional issues, and Mr. Kertcher introduced the presenters.

Presentation by Daniel Steen, FirstEnergy

Daniel Steen gave a slide presentation on measurement of net versus gross power generation for the allocation of NOx emission allowances. (See slides for details.) The information below presents highlights of the presentation and issues not included in the slides.

Mr. Steen began his presentation by noting that equipment for measuring output is extremely reliable and rarely out of service. Auxiliaries and net versus gross vary significantly from plant to plant. FirstEnergy has not taken a position on net versus gross.

Mr. Steen discussed power plant metering of electric output. Metering equipment must meet official standards (e.g., transformers are governed by Institute of Electrical and Electronics Engineers (IEEE) and meters must meet American National Standards Institute (ANSI) standards). Net and gross are more accurate indications of power plant utilization than heat input calculated from a CEMS.

Mr. Steen explained that relay and metering class are systems that put the three instruments (potential and current transformers and meters) together. To meter, one needs all three instruments. Michael Geers added that Cinergy facilities have both a metering and a relay class. A metering class is usually more accurate and used for quantifying the amount of electricity. A relay class has less accuracy but is used for a different purpose. A protective relay shuts a unit down under "fault" conditions (i.e., extremely high current flows). Depending on the application, the same instruments may be used for metering and relay purposes.

Mr. Steen discussed the trade-offs in net versus gross metering, availability versus accuracy. One member asked how often net is determined by calculation. Mr. Steen noted that this method is used at FirstEnergy, but he is unsure of the frequency throughout the industry. It would depend on the architects and engineers constructing the facilities – their purposes and concerns at the time. Another member asked if reporting requirements, dictated by utility commissions, vary widely. Mr. Steen believes that the requirements are widely variant (e.g., some commissions have performance standards and others only have a fuel clause that requests information on fuel use). A member confirmed that measurement of electrical output (net or gross) is usually more accurate than heat input. Within net and gross electrical output, net is generally measured more accurately than gross. Mr. Steen clarified that this is generally true. There are other differences between net and gross, (e.g., when net is calculated, only some net numbers may be reported). Mr. Geers added that at Cinergy, net is sometimes calculated and is sometimes measured directly. Metering class equipment for net, gross, and auxiliaries is highly accurate compared to a heat input calculation on a CEMS. The latter involves using gas and flow monitors, where the error of the system may be an order of magnitude greater. Cinergy also calculates the heat input based on chemistry analysis, which Mr. Geers believes, is more accurate than the heat input from CEMS.

A member asked to what extent do facilities have meters for direct measurement of output. Mr. Steen did not know the extent facilities are directly measuring net output, although facilities are being driven towards net measurements. One member responded that measuring net output where it ties into the grid is the most accurate assessment. Mr. Steen agreed that this would be the most accurate, down the line. Mr. Geers disagreed and noted that he believes it depends on the plant. A State agency representative commented on the burden involved with reviewing net calculations. One member commented that there is variability, but net measurements, whether calculated or directly measured, are fairly accurate. This data is already provided by non-utility power providers, and net generation determines what they are paid. Furthermore, utilities reporting their net and gross generation to EIA are using this information to calculate their rates.

Mr. Kertcher asked Mr. Geers and Mr. Steen how long they expect the transition to take to equip most power plants with instruments that directly monitor net output. Mr. Geers commented that different plants will have different motivations and that not all will transition at the same time. For example, a facility within a utility organization that is selling its own generation to its retail customers is operating in a different time frame than an independent power producer (e.g., Trigen) who is selling to the grid. The formation of Independent System Operators and transcos is fragmented and is happening at different rates in different parts of the country. Mr. Steen believed the move will be within the next year and absolutely within the next five years.

Presentation by Michael Geers, Cinergy

Michael Geers started his presentation by providing members with Cinergy's background. He noted that Cinergy is very concerned with pollution control equipment and expects to install a high level of SCR on its capacity to comply with the NOx SIP Call. Mr. Geers noted that the purpose of the process of using output-based allocations is to encourage energy efficiency in the production of electricity. One can use gross or net output. The question is how one accounts for the station auxiliaries and what types of options do plant operators have to maximize efficiency of their generating units. Pressure already exists to be efficient (e.g., utility commission oversight; competitive pressures; pressure to minimize emissions and conserve allowances; and the fact that fuel costs are about 80% of variable costs.) Output-based allocations can work with these incentives.

Mr. Geers explained the benefits of selecting gross output: (1) it is currently simpler to apply; (2) it will not penalize facilities committed to pollution control equipment; and it will still capture the desired behavior an output-based process is trying to incentivize.

Mr. Geers discussed measurement concerns and provided an illustration of an auxiliary power system at a Cinergy plant to show the complexity of these systems. Auxiliary power is often monitored in multiple locations, and pollution control equipment is rarely metered separately. The entire plant would need to be rewired to determine what power is used for the plant versus the emissions control. In multiple generating units, equipment may be shared between units. Some key sources of auxiliary power at a Cinergy station are: combustion air and flue gas fans, pollution control equipment, and fuel handling and preparation equipment. There is always some auxiliary equipment operating, even when the unit is shut down.

Mr. Geers presented a slide comparing two similar Cinergy plants (i.e., similar in size, age, and emissions rate in their operating permit) that had different pollution control equipment, one with an FGD and one without. The gross heat rate was similar for the two units; however, the net heat rate for the unit with the FGD was almost 300 Btu/kWh higher. This effect is primarily because of the FGD. A member asked about the two units' relationship to tons of NOx per ozone season. Mr. Geers noted that the NOx mass emissions rates were close (approximately 0.135 and 0.14).

Other efficiency considerations concern the age of the generating unit; type of unit (for example, drum vs. super critical); operating practices and conditions; capacity factor and the need to follow customer load. Generating units are most efficient at full load. Mr. Geers compared the spread in thermal efficiency between old and new units using gross heat rates. This spread goes beyond auxiliary power. If one was using a simple output-based method and a gross measurement, this difference would be captured and the proper incentives would be provided.

Mr. Geers summarized gross heat rate efficiency losses -- critical non-electrical efficiency variables that operators have the most control over. These variables include superheat and reheat steam temperature, steam flows and pressures, condenser back pressure, the temperature and pressure that the steam leaves the condenser, and excess combustion air needed to burn coal. Units can be made more efficient by controlling these factors, which occur even before generating electricity. Gross output would capture these factors. Mr. Geers confirmed that gross output is recorded as part of the EDRs (i.e., the Acid Rain Division (ARD) already has gross MW).

A member asked if some of the gross heat rate efficiency loss variables may be affected by pollution control (e.g., excess air). Mr. Geers responded that when a plant operates pollution control equipment, one of the biggest ways it is evident is in its auxiliary load, which increases. If a plant adds SCR to a unit, it may affect some of the combustion parameters, but the biggest impact will be in the change in auxiliary loads. The factors would still have to be optimized, but the greater penalty will be from having to factor this into the auxiliary loads. Another member asked why pollution control equipment shouldn't be penalized? He believed the purpose of an output-based approach is to encourage the construction of newer, cleaner units as opposed to retrofitting old, dirty units. Mr. Geers noted that he did not really address newer, cleaner units. He disagreed that a coal unit should be penalized just because it is a coal unit. He illustrated how the correct incentive is provided with the example of a NOx cap and trade system, where one is allowed to emit a certain number of tons of NOx. If one switched to a combined cycle natural gas turbine, where the thermal efficiency is much higher for this type of unit, one will see a bigger incentive because of its thermal efficiency. As long as an established budget is attained, the desired behavior has resulted.

Another member asked if pollution control equipment is really being penalized. If the equipment is installed, the net heat rate would decrease, but so would the NOx emissions with the reduction in NOx emissions more than covering the difference in heat rate on a net basis. Mr. Geers used the example of the auxiliary power associated with a scrubber where the NOx emissions decreased, but a high price was paid for the auxiliary power. This power could have been sold.

It was noted that a significant amount of generation in the U.S. is dependent on coal-fired steam boilers. The transition to new technology will take time. The right question to ask, "what can we do to incentivize existing coal units to become cleaner?" Penalizing pollution control equipment is the wrong message. Incentives should be provided for pollution prevention equipment for existing stock. Lower emissions depend on what control program one is referring to (e.g., flue gas desulphurization equipment for Title IV will have negligible effects on NOx). Another member added that pollution control equipment is not being penalized but instead dirtier equipment is not being grandfathered. Mr. Geers believes the argument of grandfathering is moot. An operator that has old plants, where equipment must be installed, must meet the cap.

Mark Brownstein commented that to the extent that generation has been entering the marketplace, it's mostly been due to nuclear units retiring. New development is mostly in anticipation of the loss of nuclear capacity. He agreed that new combined cycle gas units enjoy a substantial advantage in thermal efficiency, but the fuel is about twice as expensive. There is room for different incentives and signals in the market place.

Mr. Lashof suggested taking a step back in terms of the public policy question. If one accepts the premise of an output-based allocation and has two units generating the same net kWh and emitting the same amount of NOx, why would one care if one unit used inherently clean technology that required efficient auxiliaries versus another installing end of pipe controls? Isn't the premise to allocate allowances on a performance basis, with the performance in net kWh? Some members agreed with Mr. Lashof and believed the figure of merit should be emissions per unit of net output, after auxiliaries and pollution control. Mr. Geers commented that in the context of NOx, this is true. There are additional pollutants to consider, though. Mr. Lashof asked if one has a choice between two types of control equipment that could achieve the same level of NOx, why would one chose the equipment that uses more power? Mr. Geers responded by asking if one has two plants that produce the same electricity and NOx, would a customer prefer to pay $.06/kWh or $.09/kWh?

A workgroup member suggested comparing two 500 MW coal plants (as opposed to only comparing coal plants to gas plants). The first plant has a cooling tower, scrubber, and an SCR. The second plant is identical, but does not have the equipment. If one does not select gross, the incentive is to operate the higher emitting unit. A member responded that this externality occurs if the plants are not held to the same environmental performance standards. One must look at the plant's performance relative to the market clearing price of power. An operator can afford to absorb the efficiency penalties imposed when bringing a plant to environmental standards, if it will remain secure in the market. Up until this point, fuel has been a pass through cost. The industry has been indifferent to efficiency, but this is changing.

Mr. Geers concluded his presentation by noting that the purpose of an output-based approach is to introduce efficiency into the process. Many factors already award efficiency; the market will reward efficient behavior. Even if only gross output is used, a mechanism still exists to reward efficiency.

Presentation by Mark Hall, Trigen Energy

Mark Hall gave a slide presentation on output-based allocation, net versus gross. (See slides for details.) The information below presents highlights of the presentation and issues not included in the slides.

Mr. Hall explained that Trigen supports net generation of thermal and electric energy measured at the "gate" to the distribution system, which encourages facilities to minimize parasitics. (Energy used for controls, pollution control equipment, and internal needs are parasitic.) All Trigen plants measure net thermal and electricity products. Plants have choices and can tradeoff between economics, technology, environmental impacts, and products sold. Trigen supports a rational system that clearly indicates when a certain point is reached, the operator must choose between investing in a retrofit technology needed to meet an environmental objective or a technology switch that allows the plant to meet the environmental objective.

Mr. Hall noted that Trigen prepared a power point presentation on thermal measurement. He agreed to make this available on the Workgroup web site. Mr. Hall confirmed that in referring to cogeneration, he is not using a strict sequential definition of energy.

A member asked how Trigen determines how much thermal energy is used by a customer? Mr. Hall answered that it depends on a system. In all cases, all energy commodities entering a building are measured. Many old steam systems do not have condensate return. In systems that take in steam and return hot water, the rates are structured to give credit for the energy in the condensate that comes back. In systems that do not have condensate return system, this is not the case.

Mr. Lashof asked how to differentiate between a cooling tower and customer using steam and if this is a concern. Mr. Hall answered that from a public policy perspective, this probably is an important concern but from a public service supplier perspective, it is not as much of a concern. Mr. Lashof noted that if a plant produces steam for its own use, there is a concern. Mr. Hall agreed, but did not think the process for addressing this would be wise. Government could be extended to require every unit to determine where every Btu goes, but this would be cumbersome and unnecessary right now. He suggested that the box be drawn rationally -- around the plant. Other appropriate measures could be used to achieve other desired behaviors.

Presentation by Mark Spurr, International District Energy Association

Mark Spurr gave a slide presentation on how to account for steam in an output-based system. (See slides for details.) The information below presents highlights of the presentation and issues not included in the slides.

Mr. Spurr began his presentation by defining CHP or cogeneration as the generation of thermal energy and electricity and/or mechanical energy (with the focus on thermal and electricity) using an integrated process and the same fuel. There is sequential use, although the important point is that two forms of useful energy are generated with the same input fuel.

There is a diversity of configuration types. Much discussion centers on steam turbine cogeneration, although many other types of cogeneration configurations (e.g., combustion turbines, combined cycle, and reciprocating engines). Market conditions are such that combined cycles tend to be the most competitive. Mr. Spurr's recommended approach to CHP facilities is based on his appreciation of the variety of design configurations. Rather than a one-size-fits-all correction factor, he believes that steam and electricity should be approached as two separate products.

The discussion on converting steam to electricity probably stems from the thermodynamic principal that one kWh of electricity equals 3,412 Btu. However, does 1 Btu of heat equal 1 Btu of electricity? Theoretically, one could convert steam to equivalent electricity by calculating the power that would have been generated if the plant was operated in condensing mode. The NSPS arbitrarily converts steam using a 50 percent factor, but has invited further comment.

Mr. Spurr presented a graph comparing the input emission limitations as discussed in the paper he submitted to the Workgroup, where an EGU has a limit of 0.15 lbs/MMBtu and an industrial boiler has a limit of 0.17 lbs/MMBtu. If typical efficiency factors are used (i.e., EGU with an overall fuel to electricity efficiency of 34 percent, industrial boiler with an efficiency of 80 percent) and the two are put together, they can be converted to pounds of output per MMBtu. The EGU is given a much higher emission limitation per unit of output energy (0.44 lbs/MMBtu compared to 0.21 lbs/MMBtu for the industrial boiler). This is driven by the efficiency. In terms of lbs/MWh the numbers are 1.5 for the EGU and 0.7 for the industrial boiler.

Mr. Spurr concluded his presentation with three recommendations: (1) Don't "convert" steam to electricity. (2) Allocations for CHP should be the same as for separate production of electricity and steam. (3) This provides equivalent results compared to the "conversion" of steam to electricity, but is simpler and easier to verify and conceptually is appropriate from a policy perspective because it directly addresses the desired outcome.

Mr. Hall commented that many people believe that electricity is more valuable than thermal energy. Most people in the U.S. do not get thermal energy. Electricity is valuable from a monetary aspect because it's easy to distribute long distances. The value of thermal energy is that on a Btu basis, it does more work. However, it is not portable. Mr. Hall suggested examining the tradeoffs between thermal energy and electricity and treating the two as separate, different products.

Rob Sliwinski commented that this still begs the question of who gets what. At some point, a split must be made between the EGU and non-EGU pool. Equivalents must be drawn between the two pools. Mr. Spurr agreed that this question still needs to be answered, but noted that whether a State's 100 allowances are split 49-51 or 48-52, it won't make that much of a difference. This can be worked around. Mr. Sliwinski disagreed and believes the question of the split is the key question. Mr. Spurr asked how the current allocation process is done. Mr. Kertcher commented that currently, an input-based system is used. In the context of two different pools, Mr. Kertcher is unsure how these pools would be accounted for (reallocation or initial allocation) and how one would identify what allowances go into what pool. Mr. Spurr suggested basing the EGU and industrial split on the basis of input and then allocating allowances within each pool on the basis of output. Bruce Craig asked how Mr. Spurr would factor in the fuel split with a cogenerating unit. The fuel would have to be attributed on an input basis – how much fuel would be appropriated to each pool of allowances. The allowances are ultimately brought back to the unit. Mr. Spurr noted that he has not worked through a solution yet, but would, philosophically and conceptually, want to treat thermal and electric differently. He agreed to follow up with a written response to be distributed to the Workgroup.

One member agreed that electricity and steam are thermally different but noted that there are some industrial boilers that are not cogenerators. Whatever rate is used to allocate for the steam output from industrial boilers should be used to allocate for the steam output from cogenerators. The simplest approach may be to start with a steam boiler (not a cogenerator) and to allocate on an input basis resulting in "x" pounds per MMBtu. A boiler is, on average, 80 percent efficient; this could be multiplied by 1.2. Once this is done, a conversion between steam and electricity results (i.e., one would have lbs/MWh per thermal output and lbs/MWh per electric output, which could be added together to have total output that could be divided so everything is within budget). The historic split could be applied as a starting point; however, over time, this would be outdated. Members noted that this approach does not solve the problem of what to base the update on, if not input. Mr. Spurr commented on the need for an explicit adjustment factor to address the split between pools. He will develop a proposal to present to the Workgroup by the end of February.

Mr. Hall agreed that there is an issue of dividing the input between pools; however, it is not currently a pressing concern because most facilities are mostly thermal or electricity producers. The 50 percent conversion factor has no basis in any environmental reality. A mechanism that values each energy product must be found.

Mr. Steen asked for the actual breakdown between the different generator types (e.g., if 90 percent of the cogenerators are electric generating units) to put the issue in perspective. Mr. Hall stated his assumption that all non-utility generators that are selling wholesale power to utilities are showing up in the EGU database. Mr. Sliwinski added that based on EPA's definition, all cogenerators in New York are placed in the EGU pool.

Presentation by Mark Brownstein, Public Service Electric and Gas

Mark Brownstein began his slide presentation on output-based allocation for steam output from cogeneration. (See slides for details.) The information below presents highlights of the presentation and issues not included in the slides.

Mr. Brownstein began by explaining that the rationale for output-based standards is to create an economic incentive for clean generation. Air quality has been compromised to suit the needs of some incumbent companies and generation sources. Environmental regulations should be established based on environmental objectives. Then the appropriate market signals should be sent to achieve the environmental goals. Mr. Brownstein stressed that the appropriate focus of environmental regulations should be to achieve the most amount of megawatt hours, the least amount of emissions, and the least cost.

Mr. Brownstein discussed how an output-based allocation will improve upon emissions trading. An output allocation correlates the amount of energy produced and the amount of allowances received and favors production of cleaner, more efficient sources.

Mr. Brownstein discussed incorporating cogeneration into an output-based allocation method. The allocation for electrical output is straightforward; however, allocation for steam is the important issue. Mr. Brownstein discussed the options for converting to steam.

- **New Jersey example**. New Jersey allocated based on a rolling average steam output during the two highest periods of electricity production within the past three ozone seasons. Net "useful" heat output is estimated at 50 percent of production. A 0.44 multiplier was used to convert to MWh. The MWh were multiplied by 1.5 lb/MWh to convert to tons for the emission standard.

- **EPA NSPS method**. New Jersey essentially used the EPA NSPS method and applied it in its 2003 program. This method values electricity consistently across cogenerators and non-cogenerators. Steam is valued at "net-electricity" at the MWh rate.

- **Direct steam to MWh conversion**. This option would give steam a 100 percent credit (two times more tons than under the New Jersey and NSPS methodology) and is as arbitrary as the NSPS 50 percent.

- **Steam-as-electrical output**. This option makes an assumption that all steam is "de facto" considered to be pumped into generating electricity. The conversion efficiency is 38 percent. Steam is undervalued as a result.

- **Equate steam with the industrial boiler (IB) allocation**. Issues with this option are: (1) It presumes that non-utility boilers will be regulated on an output basis (which may not be the operators' presumption). (2) Better information on steam production is available from cogeneration facilities than from the industrial community because the industrial community uses its steam internally. Additional monitoring may be required. (3) Conflicts are likely regarding from which budget the tons will come. Using information from the NSPS docket, Mr. Brownstein estimated the conversion factor to be between 50 and 90 percent, with the average around 75 percent. The lack of good, publicly available data, however, makes it difficult to find a "real" factor. He suggested the Workgroup address this issue of making the conversion factor more real.

Leo Sicuranza commented that the only way one could really turn steam into equivalent megawatts is for steam to pass through a conversion device, i.e., a turbine. Currently, the most efficient turbine is a combined cycle turbine. This will not approach 75 percent; the best available is only 60 percent efficient. Mr. Craig clarified that Mr. Brownstein's chart depicting use of cogenerated steam illustrates the band of average utilization of cogenerated steam – not a conversion factor. These figures do not represent hard data but instead represent stakeholders' perceptions. Mr. Sicuranza asked if the first exercise involved looking at the steam output and determining that only 50 percent would be useful – so it was multiplied by 0.5. Next, this had to be converted to electricity. This involves multiplying it by 44 percent and reducing it to 22 percent, which is far too low. Steam being converted to electricity must be at least 33 percent in a single cycle steam cycle. Mr. Brownstein noted that the objective is not to determine how much electricity the steam would have made. The issue is how much useful energy is the steam producing and how can it be given proper credit when converting it to a common currency of MWh. Mr. Sicuranza answered that converting it to electricity is one way to give it credit. The current system is structured this way. Approximately 90 percent of the credits are being allocated to electricity. Wouldn't it be wise to establish the metric for allocation and budgets to be for electricity? If there is agreement here, then the question is, "how does one develop a fair conversion factor for the potential electricity production of steam, put everything in a common currency of electricity, then apply the same credit?" Mr. Sicuranza recommended giving credit to steam at the most efficient electricity production cycle available (combined cycle), which is approximately 60 percent.

Mr. Spurr explained that the 70 percent figure is about right for a combined cycle. He placed the graphs from his slide presentation up and noted that 0.15 lbs/MMBtu applies to an EGU and 0.17 to a non-EGU on an input basis. If one assumed that the efficiency of an EGU was 55 percent, 0.15/0.55 equals 0.27. Instead of being at 0.44 (lbs/MMBtu) one is at 0.27 Before, when one suggested multiplying thermal energy by 50 percent, one was carefully tracking the steam turbine (0.21/0.44 is close to 50 percent). Dividing 0.21 by 0.27 results in a value close to 75 percent. This results in two different values. Another member noted that this result makes sense because two different decision criteria are used. One method answers "how many allowances would have been allocated if steam and electricity were generated separately?" The other answers, "how much additional electricity would have been generated if the steam was run through an electric generator?" Mr. Brownstein commented that there is no right answer from PSE&G's point of view.

Mr. Sicuranza commented that his impression from the OTAG process was that there would be one pool (EGUs and industrial boilers). The SIP call only built the budget. States have freedom in determining their allocations. Phase I allocations in the NOx OTC used one pool. Mr. Sicuranza does not believe there is a benefit in splitting the pool.

Mr. Brownstein noted that if an output-based allocation is used and industrial boilers are part of the program, the issue of monitoring steam (to credit useful steam) must be addressed. Mr. Lashof commented that steam and electricity are not equivalent. The tradeoff operators face is whether fuel will be burned separately to make their steam, or will steam be gotten from a cogeneration unit? One must make sure that the allowances allocated for steam produced separately, are pretty close if not identical to the allowances one would get if steam is taken from a cogeneration unit. Even if one chooses not to use an output-based allocation for industrial units, the equivalent output-based allocation could be calculated. Mr. Hall agreed with Mr. Lashof and added that cogenerators selling steam are competing with self-generation of steam (usually in a boiler). Cogenerators selling electricity are selling it against self-generation of electricity in a central station type of environment. Mr. Kertcher asked Mr. Hall if he could come back to the Workgroup with an answer of how net or gross steam is measured at Trigen. This might help make this option viable. If EPA cannot identify how and what can be measured when it comes to updating, the approach cannot be implemented. Mr. Hall agreed to provide EPA with this information from Trigen but noted that that it would not answer the question for facilities that do not internally measure thermal energy (e.g., Dow and DuPont). Mr. Kertcher explained that even knowing how the calculations are done for cogenerators (gross and net) would be useful.

Mr. Sicuranza asked cogenerator operators if they measure total steam output from the boiler. If they do measure this and they measure what is sold as steam, they can determine what is going to the turbine to make electricity. Mr. Hall noted that this can be measured. Mr. Geers gave an example of a Cinergy power plant that cogenerates for an industrial facility. Steam is measured as it comes out of the boiler. It goes through the turbine and goes through additional stages. Steam comes out and goes to the industrial source. The remaining steam goes through the turbine and beyond that point, some of the steam comes out at further stages for other uses within the plant (e.g., feed water preheating). These are often not located within a unit in a measurable position. Thus, the total steam going in and the portion coming out to the industrial load are known, but the remaining steam going through is unknown. Calculating it is not straightforward. Mr. Sicuranza agreed that this example illustrates the complexity and the lack of necessity for calculating "what could we have generated if we let it do what it would have in a condensing cycle." Net power and steam output should be further examined.

Mr. Kertcher wrapped up the discussion by noting that Mr. Spurr will draft an approach for an updating scheme for a steam allocation system, and Mr. Hall will provide information on Trigen's accounting for steam and electricity output. Both inputs will be used to develop a viable approach.

Workgroup Meeting Attendees

<u>Government—Federal and State</u>
Margaret Sheppard, EPA/Acid Rain Division
Sarah Dunham, EPA/Acid Rain Division
Mary Jo Krolewski, EPA/Acid Rain Division
Dwight Alpern, EPA/Acid Rain Division
D Kimberly Scavo, EPA
Joe Bryson, EPA
Doug Grano, EPA
Jean Vernet, Department of Energy
Robert Sliwinski, NY Division of Air Resources
Arthur Diem, New Jersey Department of Environmental Protection and Energy
John Preczewski, New Jersey DEP
Joe Fontaine, New Hampshire DES

<u>Industry</u>
Daniel Steen, FirstEnergy
Mark Carney, US Generating Company
Mark Brownstein, Public Service Electric and Gas Company
Mark Spurr, International District Energy Association
Leo Sicuranza, US Generating Company
Bruce Alexander, PECO Energy
Rhone Resett, NGSA
David South, ERI
Mark Hall, Trigen
Mark Buzel, NYSEG
Michael Geers, Cinergy Corp.
David Parks, BGE
Joseph Miakisz, Niagara Mohawk
Chuck Carlin, Northeast Utilities
Barbara Bankoff for Siemens

<u>Other Organizations</u>
Bruce Craig, E3 Ventures
Debra Jezouit, Baker and Botts
Dan Lashof, NRDC
Praveen Amar, NESCAUM

<u>Contractor Support</u>
Marilyn Pineda, ICF Resources
Eva Wong, ICF Inc.

Thursday, February 4, 1999
9:00 AM to 11:00 AM
International Trade Center (Ronald Reagan Building)
1300 Pennsylvania Avenue NW
Washington DC
Room Hemisphere A

Review of agenda and previous day

Mr. Kertcher began the meeting by expressing his pleasure with the February 3 meeting and proposing a tentative schedule for additional meetings to further discuss the issues. (Members will be notified of the final times and dates through e-mail.)

- Feb. 18th Conference call to follow up on this meeting and to confirm members' commitments to providing feedback via analyses or reports.
- March 18th Workgroup meeting dedicated to presentations from members who committed to producing reports (e.g., accounting for steam) and discussions on transitioning to an output-based approach.
- April 18th Workgroup meeting dedicated to "how to."
- May 18th Workgroup meeting dedicated to member critiques of presentations by EPA staff on their reactions to the issues and a tentative proposal describing "how to" that may be included in a guidance document, at a later date, for States to use.

Conference calls will be held between each of the Workgroup meetings to line up materials and presentations for the meetings. All work should be completed sometime in the spring so that EPA can make the necessary decisions in time to prepare guidance or federal policy.

A proposed approach to output-based allocations

Joel Bluestein from the Coalition for Gas-based Environmental Solutions gave a presentation accompanied by slides on a proposed approach to output-based allocations that included alternative language for Part 96. He began his presentation by thanking staff at FirstEnergy for working with him in preparing the alternative language and staff in EPA's Acid Rain Division (ARD) for preliminary review of the material. Mr. Bluestein developed alternative rule language for allocations because of the interest in output-based allocations. Two issues stopping discussion of output-based allocations during the SIP development process are: (1) States are afraid that changing the allocation system will jeopardize swift approval of the SIP; and (2) States simply do not have time to draft revised language. (See handouts of (1) slide presentation, (2) *Notes on Alternative Language to be utilized with 40 CFR Part 96 for output-based allocation of NOx emission allowances,* and (3) *Supplemental language to be utilized with 40 CFR Part 96 for output-based allocation of NOx emission allowances* for more details.)

The goal and objective is to:

(1) Communicate to States EPA's general position on the adoption of alternative allocation language.
(2) Provide alternative language for an output-based allocation in Part 96.
(3) Allow meaningful discussion of an output-based allocation during the SIP development process.

EPA has clearly indicated that States can switch to an output-based allocation without jeopardizing approval of their SIPs. Mark Brownstein commented that when New Jersey adopted an output-based allocation for 2003 as part of their Ozone Transport Commission (OTC) Memorandum of Understanding (MOU), EPA responded that this cannot be implemented using EPA's acid rain tracking system. Arthur Diem clarified that EPA did not indicate that this was impossible but they did indicate that at that point in time, and given the time period examined, EPA did not have the infrastructure within the allowance and emissions tracking system to collect the output data themselves. Thus, the States would have to collect the output data.

Mr. Bluestein noted that data issues are addressed later in the presentation and noted that most States in the OTC are basing their allocations on their own data, not EPA's. There is no obligation for EPA to provide data to the States for allocation. Rob Sliwinski commented that this may be the current situation but that in the future, when all sources are covered, States hope to use EPA data (e.g., modified Part 75). Mr. Kertcher noted that if through this process, members determine that EPA needs to collect additional data, a rulemaking to modify Part 75 would be needed. Mr. Brownstein commented that someone in the federal government is collecting output-based data; although this collection may need to be improved, could this data be used or would the data have to be EPA collected data? Leo Sicuranza explained that his understanding of the phase II systems in the OTC is that the ARD assigns allowances to a State general account; the States disperse the allocations according to their individual formulas. The ARD only tracks the tons. During the "true up" the ARD informs the States of how many tons each unit has emitted. The States take the data back to the units and determine compliance. Mr. Sicuranza asked if this system is going to be changed, or if not, is this issue a State versus ARD issue? Mr. Diem commented that in New Jersey for 1999, the State collected its own heat input data for use in its allocation formulas. For 2000, the State would like to use data reported in the EDR for determining its allocations. Mr. Kertcher noted that EPA is anticipating having to prepare Federal Implementation Plans (FIPs) in some States and is deciding whether to use an input- or output- based approach.

Mr. Bluestein explained that the alternative language was developed to explain how States can apply an output-based allocation within the structure of Part 96. He directed members to data used to develop the alternative language: **www.eea-inc.com/part96.html** and described the areas addressed in the modifications to Part 96 (applicability, definitions, allocation methodology, treatment of cogeneration, and data sources. See slides for more detail.) With regard to applicability, the alternative rule language has been modified to include all forms of electric generation. States that wish to restrict the applicability to combustion units only, or some other set of generation sources, will have to adjust the definition of "unit" in section 96.2. Other definition changes relate to referencing output rather than input and adding a definition of "cogeneration." Mr. Bluestein reminded members that the definitions are presented in the handouts on the alternative language.

Electric and Thermal

The basic concept of the allocation method is that each unit receives allowances proportional to its share of output, either electric or thermal. If an electric generating unit (EGU) generates five percent of the MWh, it should receive five percent of the allowances in the State. The output-based method parallels the input-based method. Allocations are based on a nominal output-based rate (1.5 lb/MWh or 0.2lb/$MMBtu_{out}$) and then are normalized to the total budget. Mr. Bluestein clarified that the 1.5 is related to the 0.15 in the original; the 0.2 is the 0.17 divided by 85 percent efficiency. Dan Lashof asked if there are separate budgets for electricity versus thermal. He suggested applying the nominal allocation to both electric and thermal output using the nominal rates, adding the totals, then normalizing the total pot. Mr. Bluestein noted that although EPA established an EGU and a non-EGU budget, States have the flexibility to work from one budget. He added that with cogeneration allocations, the issue of moving tons from one pool to another is raised. Because essentially output is one pool and States can decide how to allocate it, the issue of one or two pools is not of immediate concern. Mr. Bluestein stressed that allocation is not compliance. He raised a bookkeeping issue regarding the discrepancy between the current tracking system's use of units (the current tracking system deals with combustion units) and measurement points (point of generation). Currently the combustion units do not match the stacks. Allowances may need to be tracked back to the unit. This discrepancy may need to be resolved for bookkeeping purposes.

Mr. Bluestein believes that regardless of the number of pools, in the output-based approach, cogeneration sources should get their share of allocations from both EGUs and non-EGUs. Essentially, one or two pools is an issue of semantics. Sources get credit for their production. Mark Spurr commented that there is no way around establishing two separate pools and suggested that combined heat and power (CHP) units be ignored when setting the initial allocation between EGUs and non-EGUs.

Mr. Lashof noted that the real issue is whether one or two normalization factors are applied to the nominal electric and thermal rates. In the end, the pools are effectively split but the normalization factor(s) will result in slightly different answers. A member noted that this was an issue with the New Source Performance Standards (NSPS) treatment of cogeneration. There is a difference in efficiency between electric and thermal output in a conventional unit. In the NSPS, the utility boilers were allocated tons based on 1.5 lb/MWh, which was derived from 0.15 lb/MMBtu input. The industrial boilers had an input-based standard of 0.2 lb/MMBtu. Thus, the industrial boiler standard seems less stringent than the utility boiler standard. But when one works through the efficiency, if calculated on the Btus on an output basis, the utility boiler receives twice the allocation than the industrial boiler. Starting with one pool, if allocations are based on 1.5 lb/MWh or 0.2 lb/$MMBtu_{out}$ and then normalized, the answer would differ from the answer if one starts with input, defines two pools, and then allocates the two pools based on the numbers. Mr. Lashof agreed that the numbers would differ but would probably be close. Over time, the difference may increase. He noted that one needs to determine which approach is better and why one would conceptually permanently want two pools.

Mr. Sliwinski commented that States do not want two pools given the changing market. Having two set pools is an obstacle. Mr. Bluestein responded that two pools for allocation does not mean two pools for trading and compliance. Mr. Sliwinski agreed but commented that the purpose of allocation is to apply the fairest method possible to get things where they need to be. Mr. Diem commented that this issue will greatly impact facilities such as refineries because the EGU pool is based on cogeneration. All the heat input is going in the EGU side. If this is moved from the other side, it might constrain facilities such as refineries who would initially receive an allocation that would represent a stricter NOx situation. Mr. Bluestein commented that moving tons from the industrial side will affect everyone on the industrial side proportionally. If an industrial cogeneration unit generates less than 25 MW, it is probably in the non-EGU pool, which means that tons will come into the non-EGU side. The calculations will be State specific. Mr. Diem commented that having one pool and normalizing one way would remove a lot of these issues.

Data Issues

Mr. Bluestein discussed data issues and explained his understanding that in the long run, EPA will be collecting data for all sources (EGU and non-EGU). This may be as early as three years from now. A member asked if EPA will collect available output data or require output data from all sources, including industrial. Mr. Bluestein's understanding is that EPA will be requiring this data through a vehicle such as a modified Part 75.

In the short run, Mr. Bluestein is concerned with what can be done at the State level using existing output data sources or approximations. Enough available information exists to perform an output-based allocation this year (e.g., on the EGU side EIA forms 767 and 759, State collection, and IPM™ data used in the FIP, all provide data). There is a lack of data on the non-EGU side, however, with data collected under State requirements being the best source. A proposed alternative is to calculate output, based on input and a nominal efficiency. This allocates the tons the same as input but establishes the structure for future output-based allocations. Margaret Sheppard noted that the draft regulatory language does not clearly indicate if this is Mr. Bluestein's recommended approach. Mr. Bluestein answered that the original language references Part 75, which today includes nothing for industrial boilers. Thus, the language reads Part 75, or whatever data the State has.

Mr. Bluestein noted that the largest language change involved accommodating cogeneration units because they can show up in the EGU or non-EGU side. He cautioned that the language might be cumbersome because at every stage, thermal or electric and thermal and electric from cogeneration units in the other category must be addressed. Further, if a State decides it likes the output approach for EGUs but not for non-EGUs, it can apply both approaches. A member commented that if one is using an input-based approach with a bad conversion factor, the result is a lower allocation, which encourages one to put in measurement devices for accurate output. Mr. Bluestein added that within one sector, everyone must adopt the same approach. He agreed that on the data measurement side, if one has sources on the non-EGU side and one chooses a certain efficiency (i.e., one has the source's heat input measurement and the efficiency factor in the absence of measured data), this would encourage one to install better measurement devices.

Mr. Bluestein summarized his presentation by noting that States have the option to allocate based on output. The alternative language is available for States to use. It is better to set up the output-based structure now and allow the data to improve than to reconstruct the whole system later.

Mr. Bluestein clarified that the only EIA data he has is for electric utilities. Mr. Lashof noted that OMB approved the EIA confidentiality changes to provide NUG and utility generation data. Ms. Sheppard commented that EIA was discussing going back retrospectively to the beginning of 1998 because this data has not been released yet. The old confidentiality policy would still apply to the 1995-1997 data.

Day One Wrap-up

Mr. Kertcher commented that future meetings will be one day. He summarized the positions expressed by members:

Gross versus net generation

Members comments on gross generation were:

- It is measured directly by plants.
- It is already reported to EPA (electric for EGUs). Ms. Sheppard clarified that non-acid rain sources using the missing data procedures for NOx CEMs will report this data.
- It places units with emission controls in a better competitive position than a similar unit without controls and still provides incentives for greater efficiency within the plant. Mr. Bluestein clarified that only the same types of units are comparable with regard to the competitive position. Pollution prevention is not quite comparable. A unit using low sulfur coal meeting the same standard as a unit with a scrubber will be more efficient but at a competitive disadvantage.

Members comments on net generation were:

- Plant emissions can be linked to the market value of electricity, creating a level playing field.

- It might encourage cleaner, more efficient plants using less auxiliary power for pollution control, and it provides value for pollution prevention and creates greater incentives for efficiency within the plant.
- It may be monitored more accurately than gross generation.
- "Net" should be defined as net of the auxiliaries required to generate power or steam, not "net" of uses within the plant for processes. Output consumed within the building is net generation that would need to come from another source, otherwise. Bruce Craig added that it requires a facility to draw a tight fenceline around the generating unit. Mr. Sicuranza suggested members seek guidance from the independent system operators regarding uses and charges.
- In many cases, net is already measured and will be measured even more with restructuring.

Steam

Members positions on steam were as follows:

- Most members think it's easier to deal with steam separately from electricity, although in the context of allocations they are ultimately combined.
- In the short-term, EPA is examining steam on an input-basis, although conversion factors may be used to express input as output. This conversion is advantageous in that it structures regulations in an output-based format. Thus, when data is collected from non-EGUs, the data could just be updated.
- Mr. Sicuranza expressed his belief that there was not consensus regarding the use of one or two pools. Mr. Lashof noted that the general consensus was not regarding the number of pools but was that it did not make sense to convert steam to electricity for allocation purposes.
- Mr. Spurr commented that many combustion systems produce both steam and electricity. Converting steam to equal electricity is a theoretical, arbitrary exercise that may be necessary in the near term. Overall, though, thermal energy and power are different commodities and should be treated that way. Another member added that a key principle is that the steam side of a cogeneration plant should receive the same allocation as steam produced in a thermal only plant, regardless of method. Mr. Bluestein commented that applying Mr. Lashof's principle of consistency would result in the right factor.
- Mr. Spurr suggested adding the principle that the credit or allocation for thermal should be consistent from CHP to non-CHP boilers. This consistency is preferable to an arbitrary percentage.
- Members also suggested including Mr. Bluestein's suggestion to start using an output-based approach now. Mr. Bluestein noted that the draft revised regulatory language for a State SIP has been developed and is available (although not approved by EPA).

Mr. Kertcher summarized that members want EPA to identify how to account for thermal output for cogeneration and industrial boilers. Presuming this is possible, the allocations should be developed separately (thermal versus electric). These would come together in a State's pool. EPA's work over the next month involves investigating how measurements are or should be made and whether data exists or not.

Next Steps

Sarah Dunham summarized the issues that EPA is considering in evaluating the merits of an output-based allocation. These issues include:

1) Permanent versus updating allocations;
2) Input versus output; and
3) Allocating to fossil fuel sources only or to all sources.

EPA is also considering the following:
(1) Will giving allowances to plants affect their internal operating procedures?
(2) Will there be any potential change in fuel type or mixes of fuel types used to generate electricity?
(3) Will there be impacts to total electricity generation?
(4) As a result of these three possible changes, are there any environmental or economic implications?

Mr. Brownstein suggested EPA also examine how budgets were established in the first place. He recognizes that this would not affect the SIP call but believes it would help in developing future frameworks for other pollutants. Mr. Lashof added two additional issues related to the implications Ms. Dunham listed: (1) The dynamics of decisions to build new plants versus operating existing plants; and (2) Implications for electricity prices depending on the approach.

Mr. Kertcher clarified that EPA would appreciate having volunteers give presentations on these issues at future meetings. Ms. Sheppard suggested laying out the questions in written form and soliciting answers. The next conference call could be used, in part, to structure solicitation. Mr. Bluestein clarified that he is open to comments but that his goal is to make this information available to States. Dwight Alpern noted that the interaction between the definitions in the alternative language and existing parts of the rule (e.g., monitoring) need to be examined because the definitions may cause problems in other parts. Mr. Bluestein agreed to examine this issue.

Postscript: As EPA stated on the February 18, 1999 conference call, the Agency will not be able to discuss issues concerning the appropriateness of updating output-based allocations with the workgroup. This is because of legal constraints while EPA is finalizing rulemakings that deal with these issues.

Conference Call Attendees

Government—Federal and State

Margaret Sheppard, EPA/Acid Rain Division
Sarah Dunham, EPA/Acid Rain Division
Mary Jo Krolewski, EPA/Acid Rain Division
Dwight Alpern, EPA/Acid Rain Division
Jean Vernet, Department of Energy
Robert Sliwinski, NY Division of Air Resources
Dave Bassett, U.S. DOE
Kimberly Scavo, EPA
Joe Bryson, EPA
Doug Grano, EPA
Arthur Diem, New Jersey Department of Environmental Protection and Energy
John Preczewski, New Jersey DEP

Utility/Electric Power Industry

Daniel Steen, FirstEnergy
Mark Carney, US Generating Company
Mark Brownstein, Public Service Electric and Gas Company
Mark Spurr, International District Energy Association
Leo Sicuranza, US Generating Company
Bruce Alexander, PECO Energy
Rhone Resch, NGSA
David South, ERI

Other Organizations

Bruce Craig, E3 Ventures
Joel Bluestein, Coalition for Gas-Based Environmental Solutions
Dick Ayers, Howery and Simon
Thomas H. Harman, Inside Washington Publishers
Debra Jezouit, Baker and Botts

Contractor Support

Marilyn Pineda, ICF Resources
Eva Wong, ICF Inc.